BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR APPROVAL OF ITS PROPOSED ELECTRIC RATE SCHEDULES & ELECTRIC SERVICE REGULATIONS	)	Docket No. 05-035-___ DIRECT TESTIMONY OF MARK T. WIDMER

NOVEMBER 2005

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Mark T. Widmer, my business address is 825 N.E. Multnomah, Suite 800, Portland, Oregon 97232, and my present title is Director, Net Power Costs.

Qualifications

Q. Briefly describe your education and business experience.

A. I received an undergraduate degree in Business Administration from Oregon State University. I have worked for PacifiCorp since 1980 and have held various positions in the power supply and regulatory areas. I was promoted to my present position in September 2004.

Q. Please describe your current duties.

A. I am responsible for the coordination and preparation of net power cost and related analyses used in retail price filings, the Integrated Resource Plan (IRP) process and the Multi-State Process (MSP). In addition, I represent the Company on power resource and other various issues with intervener and regulatory groups associated with the six state regulatory commissions which have jurisdiction over the Company.

Summary of Testimony

Q. Will you please summarize your testimony?

A. I provide quantitative analysis of the Company's historical net power cost exposure and how that relationship has changed to the point that the Company's risk has become very asymmetrical. I present the Company's proposed Power

Cost Adjustment Mechanism (PCAM), which if adopted, would better balance net power cost exposure between the Company and customers.

Asymmetric Risk

Q. Why is the Company requesting a PCAM?

A. The Company's net power cost exposure to losses is asymmetric. Market prices can only fall to zero while market price increases are, theoretically, unlimited. Even though it is unlikely that market prices will fall to zero or increase infinitely, the limitations are relevant. For example, as explained below, since 1989 the largest decrease in net power costs is dwarfed by the largest increase in net power costs above authorized levels. This is causing the Company to bear a disproportionate share of net power costs incurred to serve retail customers. As a consequence, our opportunity to earn our authorized rate of return over the long run will be greatly diminished if not eliminated, because net power costs are such a large component of revenue requirement.

Q. Please define net power cost exposure.

A. In this context I have defined net power cost exposure as the variance between actual and authorized net power costs.

Q. Please explain the information shown on Exhibit UP&L___ (MTW-1).

A. Exhibit UP&L___ (MTW-1) shows the historical net power cost exposure experienced from 1990 through 2004. These figures exclude the $146 million recovered from Utah customers for the energy crisis. As shown, the net power cost exposure varied between a $32 million gain and a $738.5 million loss on a total Company basis, excluding recovery for the energy crisis. In aggregate and including recovery for the energy crisis, losses exceeded gains by $1.1 billion total Company based on Utah authorized net power costs.

Q. Has the Company's net power cost exposure been constant over that period?

A. No. Beginning in 2000, with the start of the Western energy crisis, the exposure has become very asymmetric. From 1990 through 1999, the Company's net power cost exposure averaged $7.1 million total Company and from 2000-2004 it averaged approximately $223 million in excess costs. In percentage terms, the exposure for the 2000-2004 period increased by over 3,100 percent compared to the 1990-1999 period average.

Q. Are the factors which contribute to the net power cost exposure asymmetry controllable by the Company?

A. No. Deviations from net power costs in rates are primarily related to factors not controllable by the Company. For example, hydro conditions, weather conditions, retail loads, wholesale market prices for natural gas and electricity and the timing of forced outages are not controllable. While these potential causes have always been present, the cost of addressing these factors has increased dramatically over the past 5 years. The overwhelming cause of the cost increase is due to an increase in wholesale market prices and price volatility. For example, actual hydro generation for fiscal 2004 was 1.5 million MWh below normal due to continued drought conditions. At market prices prevalent from 1990 through 1999, replacement power would have cost $25 million on average. At recent market prices, replacement power would have cost approximately $120 million. Historical market prices are shown in Exhibit UP&L___ (MTW-2). More recently we have seen natural gas prices approximately double over the last year alone. Unless changes are made to the Company's Utah net power cost recovery regulatory model, this asymmetry will continue to increase as wholesale market prices and price volatility increase.

Q. What is the expected trend for the wholesale market price of electricity?

A. While the expected trend is down from the current high levels over the next several years, the prices are expected to stay high by historical standards and there will be some level of year-to-year volatility in wholesale market prices. Exhibit UP&L___ (MTW-3) is the Company's most recent Official Price Projection of future market prices.

Q. Have prudent steps been taken to insulate customers and shareholders from net power cost exposure?

A. Yes. The Company engages in the IRP process. Through the IRP process the Company identifies resource requirements which have resulted in the Company filing request for proposals ("RFPs") for resources to meet load requirements on a least-cost, risk-adjusted basis. This process provides further assurances to the Commission and customers as to the prudent nature of our net power costs involving power purchases and/or the construction of generation facilities. The Company has also increased its emphasis on transactions that would reduce risk. These efforts were undertaken to further align the interests of shareholders and customers. Finally, under the proposed PCAM described below, the sharing bands would result in the Company shouldering a significant portion of the volatility between rate cases, thereby reinforcing the Company's incentive to manage its system and associated risks prudently.

Q. Has net power cost exposure been recognized and addressed by other Commissions that regulate utilities located in the WECC?

A. Yes. As described in a recent Standard and Poor's research article titled "Fuel and Power Adjusters Underpin Post-Crisis Credit Quality of Western Utilities", Exhibit UP&L___ (MTW-4), most of the investor owned electric utilities located in the WECC currently have some form of power cost recovery mechanism, with the exception of a few utilities including PacifiCorp and Portland General Electric (PGE), and Public Service of New Mexico and Tucson which are resource long. An important factor that should be considered in the Commission's evaluation of our request is the fact that the Company has more exposure than many of the other utilities located throughout the WECC due to variability of hydro resources in our portfolio.

Q. How does the Company propose to rebalance the asymmetric net power cost exposure that the Company has been shouldering?

A. The Commission should adopt the Company's proposed PCAM to rebalance net power cost exposure between customers and the Company so they are closer to historic levels. Failure to do so would likely result in a systemic under recovery of net power costs that are prudently incurred to serve customers and would not consistently provide our customers proper price signals for energy consumption decisions.

Proposed PCAM

Q. Please explain how net power costs will be recovered in Utah under the Company's proposed PCAM.

A. The PCAM is an incentive-based mechanism that would share variations in adjusted actual net power costs from the authorized baseline net power costs with one exception. The one exception is that 100 percent of cost increases or decreases related to Qualifying Facility (QF) contracts should be recovered from customers since the purchases are required by PURPA. In addition, the 2005 Energy Policy Act (EPAct) requires that electric utilities recover all prudently incurred costs. Section 210 (m) (7) states:

> The Commission shall issue and enforce such regulations as are necessary to ensure that an electric utility that purchases electric energy or capacity from a qualifying cogeneration facility or qualifying small power production facility in accordance with any legally enforceable obligation entered into or imposed under this section recovers all prudently incurred costs associated with the purchase.

All other costs would be subject to asymmetrical sharing bands that allocate 90 percent of cost increases to customers and 100 percent of cost decreases to customers.

Q. Please explain how the proposed PCAM will operate.

A. In the ongoing operation of the PCAM, base net power costs in rates will be established in general rate cases. Deferred Net Power Costs will be calculated monthly and are equal to the Utah allocated share of the difference between total Company Base Net Power Costs and total Company Adjusted Actual Net Power Costs plus a Utah retail load adjustment. If the Deferred Net Power Costs is positive, the Company has collected more from customers than the costs incurred and 100 percent of the net excess will be returned to customers over a 12 month period. If the Deferred Net Power Cost is negative, the Company has collected less from customers than the costs incurred and only 90 percent will be recovered from customers over a 12 month period. In other words, if the Company recovers less than the Adjusted Actual Net Power Cost, the Company will absorb 10 percent of the cost increase as risk sharing. This asymmetric risk sharing mechanism will provide the Company a significant incentive to keep total net power costs as low as possible while providing safe, adequate and reliable service. Mr. Taylor describes the steps necessary to allocate the deferrals to Utah pursuant to Revised Protocol.

Q. Please explain the Utah retail load adjustment.

A. The adjustment captures the monthly retail revenue impact of changes in Utah load from the level included in retail rates. Through this adjustment, increased retail revenue related to load increases is netted against increased net power costs and conversely, revenue decreases related to declines in retail loads is netted against decreased net power costs. The revenue adjustment would be calculated by multiplying the portion of the retail rate related to net power costs by the change in load from the in rates level.

Q. Should the accrued balances accrue interest?

A. Yes. Both customers and the Company should be compensated for the time value of money for accrued balances, whether positive or negative. The interest rate used should be the Company's authorized rate of return.

Q. Please define and describe the terms that the Company proposes for the management of the PCAM.

A. **<u>Base Net Power Costs</u>** are the authorized net power costs in rates. The measurement period should be tied to the balancing account trigger, which is discussed below. Base Net Power Costs will be in effect until the Company's rates are adjusted through a general rate case.

<u>Adjusted Actual Net Power Costs</u> is the sum of the total Company amounts recorded in FERC Accounts: 501, 503 and 547 (Steam Production Fuel Expense) for coal, steam and natural gas purchased and or sold, 555 (Purchased Power), 565 (Wheeling), 447 (Sales for Resale). These actual amounts would be further adjusted to; 1) remove actual costs consistent with the rate setting process so comparable costs are being used in the accrual calculation, 2) remove prior period accounting entries recorded during the accrual period that are not applicable to the current period, and 3) to include Commission-adopted disallowance adjustments from the most recent Utah rate case so comparable costs are being used in the accrual calculation. An example of an item 1 adjustment would be the removal of Bonneville Regional Credit costs because they are not applicable to Utah. An example of an item 2 adjustment would be the removal of fuel costs booked to the current period that are related to a historical period outside the measurement period. An example of an item 3 item adjustment would be the Commission adopted Sacramento Municipal Utility District (SMUD) wholesale sales revenue imputation adjustment.

Trigger is the $20 million Deferred Net Power Cost threshold balance at which the Company may return or recover balances accrued from customers.

Q. Is the Company proposing to establish a fixed schedule for requesting recovery of or return to customers of accrued balances?

A. No. Rather than establishing a fixed schedule for such filings, the Company proposes that a plus or minus $20 million accrued balance on a Utah basis be established as a trigger. Once the trigger is reached, the Company can return or collect balances from customers. This approach is more beneficial than setting a fixed schedule because it should reduce the number of rate changes during periods of lower net power cost volatility, reduce rate shock during periods of higher volatility when balances could be much higher, and provide more current price signals during periods of higher volatility.

Q. How does the Company propose to allocate the sur-charges and sur-credits to customers?

A. Both will be spread to customers on a uniform cents-per-kwh basis to all customer classes in order to reflect changes is costs per MWh incurred by the Company to serve customers. Because differences in delivery voltage result in different line losses and power requirements, the Company proposes to vary the sur-charge and sur-credit amounts by delivery voltage. The loss factors in effect at the time time of the accrual would be used for this determination.

Q. Is the PCAM designed to take into account all net power cost components?

A. Yes. The mechanism is designed to include the impact of cost changes for fuel, wheeling and purchase power expenses and wholesale electricity and natural gas sales modeled in the Company's production dispatch model.

Q. Please explain Exhibit UP&L__ (MTW-5).

A. Exhibit UP&L__ (MTW-5) is an illustration of how the Company's proposed PCAM would have operated during calendar year 2004. As shown, the total Company net power cost variance from Utah authorized results was $233.6 million. After exclusion of the Company's $22.2 million share, $3.3 million was related to east hydro, $.4 million was related to Mid Columbia hydro. $5.5 million was related to existing QF contracts, .8 million was related to new QFs and $$62.5 million was related to all other, which includes fuel prices, market prices, contract changes etc. Utah's allocated share of these costs would have been $$72.4 million. The revenue impact of the load changes was $(40.9) million, leaving a net Utah impact of $31.5 million.

Q. Is the proposed PCAM similar to currently effective commodity balancing account mechanism used by Questar?

A. Yes, the function of the proposed PCAM is similar to Questar's natural gas commodity balancing account. The major difference is that the Questar mechanism provides 100% recovery of cost increases and the Company's proposed mechanism provides recovery of 90 percent of cost increases between rate effective periods.

Q. Should accrued costs be subject to a prudence review?

A. Yes. However, costs and revenues related to existing contracts and resources that have previously been included in rates should be exempt from a prudence review on a cost basis. Of course, the manner in which in which generation facilities were operated and contracts dispatched during the accrual period should be subject to review along with other new contracts. This review is also intended to cover whatever accounting issues may arise and ensure that Commissions disallowances are accounted for properly.

Q. Does this conclude your direct testimony?

A. Yes.

PacifiCorp
Exhibit UP&L _____(MTW-1)
Docket No. 05-035-___
Witness: Mark T. Widmer

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer

Net Power Cost in Rates vs Actual
1990 - 2004

November 2005

PacifiCorp
NPC In Rates Vs Actual
1990-2004

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
NPC in Rates	392.0	392.0	392.0	392.0	392.0	392.0	392.0	392.0	392.0	377.3	404.8	471.9	589.0	589.0	531.3
Actual NPC	393.9	393.5	407.4	372.2	402.4	360.0	400.9	369.9	444.8	431.7	841.1	1210.4	677.7	598.2	745.6
Difference	(1.9)	(1.5)	(15.4)	19.8	(10.4)	32.0	(8.9)	22.1	(52.8)	(54.5)	(436.3)	(738.5)	(88.7)	(9.2)	(214.4)
Average Difference					(7.1) 1990-1999								(297.4) 2000-2004		
										Excess Power Cost Collection			366.6		
													(224.1) 2000-2004		

PacifiCorp
Exhibit UP&L _____(MTW-2)
Docket No. 05-035-___
Witness: Mark T. Widmer

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

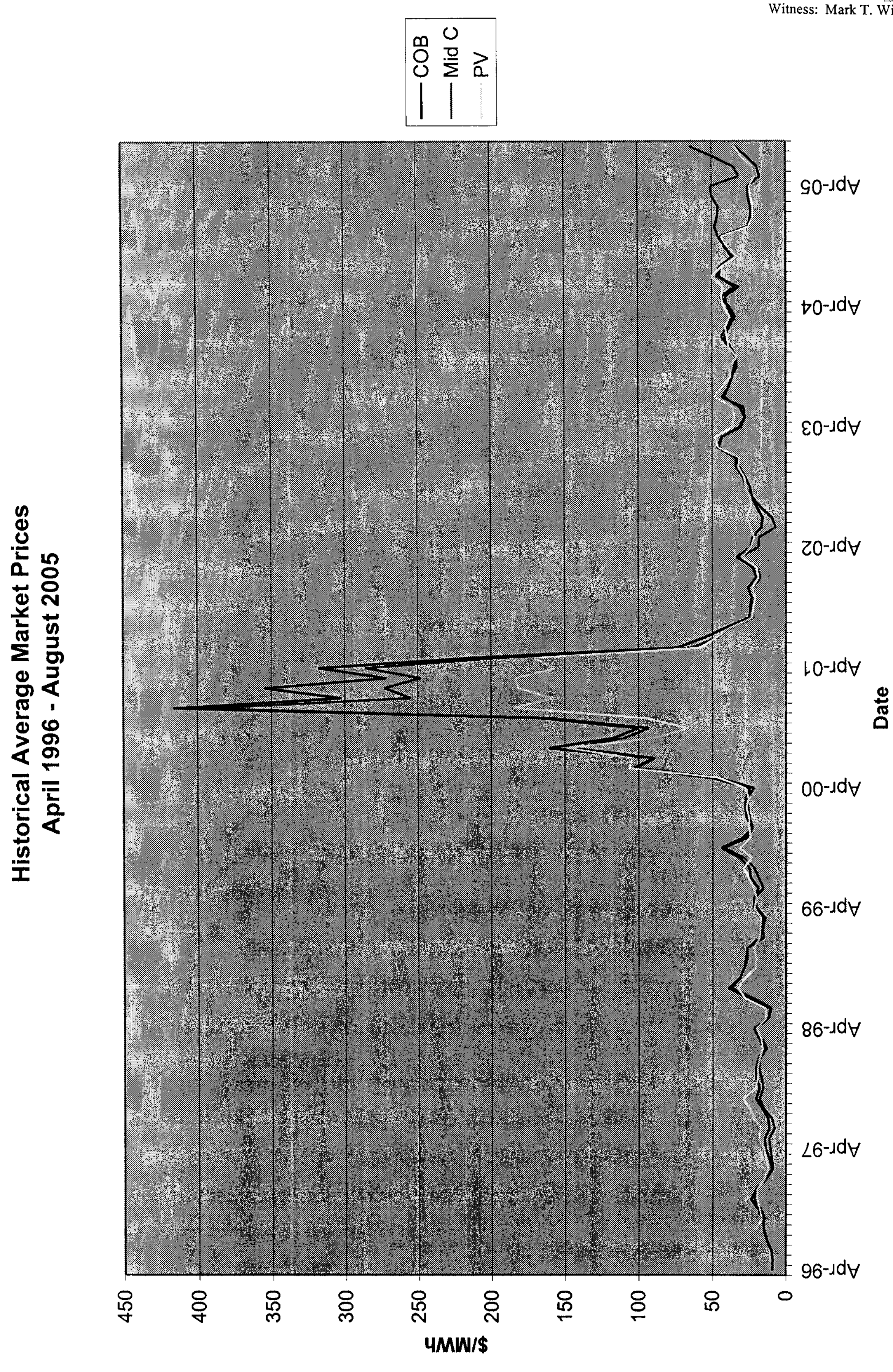
PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer

Historical Average Market Prices
April 1996 – August 2005

November 2005

PacifiCorp
Exhibit UP&L__(MTW-2)
Docket No. 05-035-__
Witness: Mark T. Widmer



PacifiCorp
Exhibit UP&L _____(MTW-3)
Docket No. 05-035-___
Witness: Mark T. Widmer

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

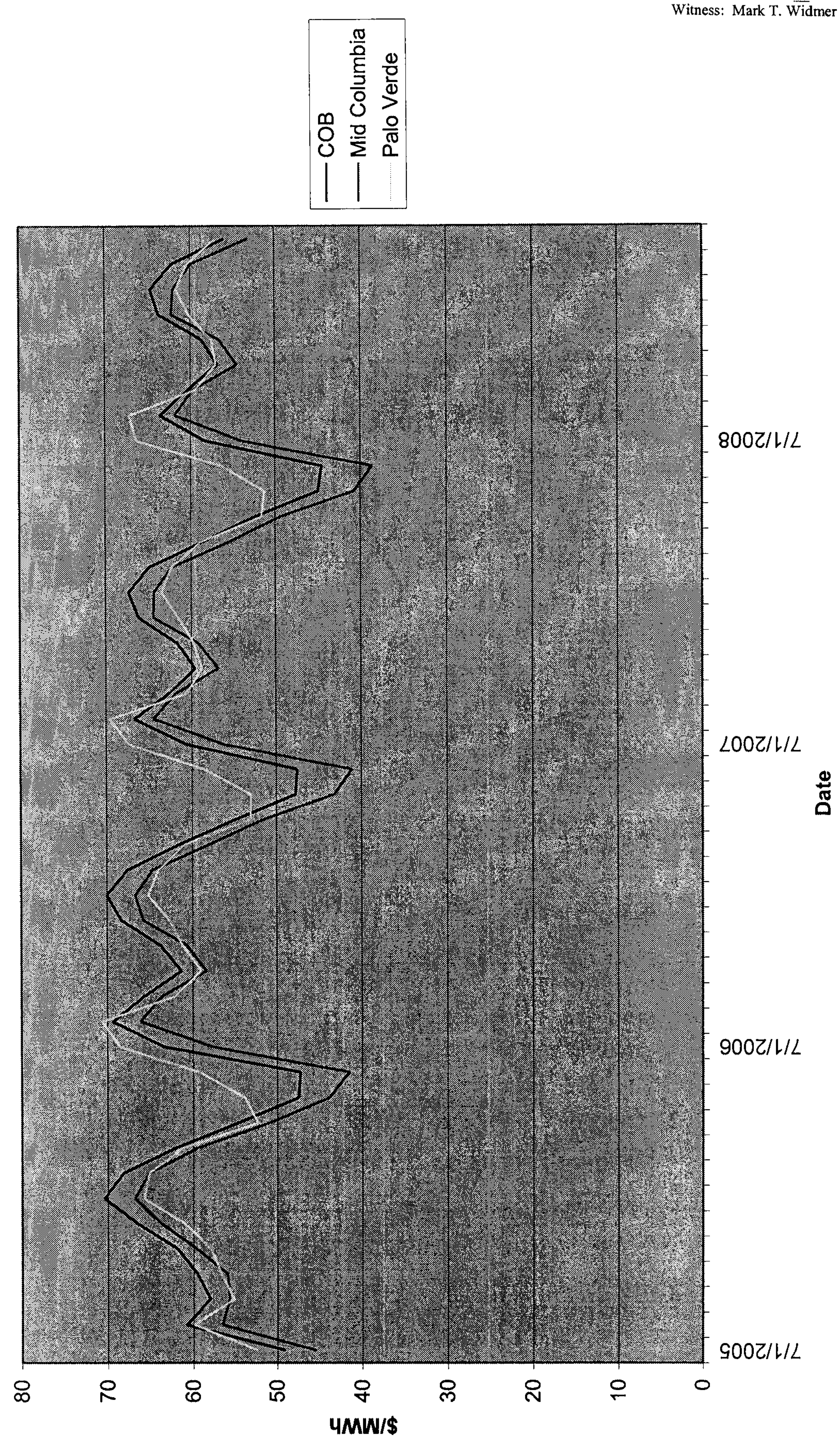
Exhibit Accompanying Direct Testimony of Mark T. Widmer

Forecast Average Market Prices
July 2005 – March 2009

November 2005

PacifiCorp
Exhibit UP&L__(MTW-3)
Docket No. 05-035-__
Witness: Mark T. Widmer

Forecast Average Market Prices
July 2005 - March 2009



PacifiCorp
Exhibit UP&L _____(MTW-4)
Docket No. 05-035-___
Witness: Mark T. Widmer

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer

Standard & Poor's Article
"Fuel and Power Adjusters Underpin Post-Crises Credit Quality of Western Utilities"

November 2005

PacifiCorp
Exhibit UP&L__(MTW-4) Pg. 1 of 5
Docket No. 05-035-__
Witness: Mark T. Widmer

STANDARD &POOR'S | RATINGSDIRECT

Return to Regular Format

Research:
Fuel and Power Adjusters Underpin Post-Crisis Credit Quality of Western Utilities

Publication date: 14-Oct-2004
Primary Credit Analyst(s): Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

It has been more than three years since the California energy crisis led to the rapid deterioration of credit quality for many western electric utilities. The financial distress that visited public power and investor-owned utilities (IOU) was in part attributable to the absence of fuel and purchased-power adjustment mechanisms (FPPA), coupled with a reliance on the wholesale market for significant supplies. It is not an oversimplification to say that IOUs that emerged relatively unharmed from the energy crisis benefited substantially from FPPAs, while those that suffered the most did not have FPPAs.

The severe market distortions of the California crisis have faded, but FPPAs continue to play a significant role in the financial well-being of western electric utilities. Natural gas volatility, poor hydro conditions in the Northwest, the Southwest's sustained drought, and uncertainty over future generation development are daily reminders that it is increasingly difficult for utilities to sustain their financial health solely through the use of hedging policies and regular general rate case filings. This article examines the progress by major western utilities in instituting FPPAs since the California crisis and comments on FPPA attributes that are important for credit quality.

What is an FPPA?

The overwhelming majority of a utility's expenses are concentrated in two categories--purchased power and fuel. Electric utilities that have the greatest exposure to significant cost swings are those that have sizable gas-fired generation and rely on power purchases that are indexed to market prices. Table 1 illustrates the proportion of 2003 expenses devoted to these two items for 12 western IOUs, and provides a measure of the dependence on gas and power purchases to meet load requirements.

Table 1 Largest IOUs in the West Without Fuel and Purchased-Power Adjusters

	Total fuel expenses (Mil. $) in 2003	Total purchased power expenses (Mil. $) in 2003	Percent of total expenses that is fuel and purchased power	Percent of retail sales supplied with own generation*	Percent of MWh from owned gas generation¶
Puget Sound Energy Inc.	65	649	35.2**	35.6	11.1
Avista Utilities/Avista Corp.	36	148	17.6**	73.8	7.4
Idaho Power/IDACORP Inc.	100	151	35.1	100.6	0.3§
Arizona Public Service/Pinnacle West Capital Corp.	703§§		36.1¶¶	84.5	4.9
Tucson Electric Power/UniSource Energy Corp.	210	65	34.4	136.9	4.0
PacifiCorp/PacifiCorp Holdings Inc.	482	1,213	50.5	107.7	4.1
Nevada Power Co./Sierra Pacific Resources	320	744	60.3	54.6	42.8
Sierra Pacific Power/Sierra Pacific Resources	321	745	53.1**	47.0	59.6
Portland General Electric Co.	1,028§§		60.2	43.0	17.3§

Public Service Co. of New Mexico	141	803	67.3**	134.4	2.1§
Southern California Edison Co.	235	2,786	39.2	63.7	-
Pacific Gas & Electric Co.	0	2,319	70.4**	36.0	1.7§

*Based on data provided by Platt's. ¶Based on company 10K filings, except where indicated by §, in which case data is provided by Platt's. **Combined utility (gas and electric). ¶¶Includes trading and marketing operations. §§Arizona Public Service and Portland General Electric fuel and power expenses are not separately broken out.

An FPPA allows utilities to automatically flow through retail rates any changes in fuel and purchased-power costs. An FPPA circumvents the need for a utility to file a formal rate case to adjust retail rates to reflect changes in these costs, and significantly increases the probability that an IOU will collect fuel and power costs from ratepayers in full and on a much more timely basis. This is accomplished typically through monthly tracking of costs, with periodic true-ups of a utility's forecast versus actual fuel and power costs, typically annually.

Which Western IOUs Have Instituted FPPA?

In 2000, the largest IOUs in the western U.S. did not have FPPA, and their credit ratings generally suffered as a result of the market disruptions that occurred beginning in 2001 (See table 2) Today, the majority of western utilities have some form of FPPA.

Table 2 Fuel and Purchased-Power Adjusters

Utility/Holding Company	2000 Rating	FPPA in 2000?	2004 Rating	FPPA in 2004?
Puget Sound Energy Inc.	BBB+/Negative/A-2	No	BBB-/Positive/A-3	Yes
Avista Utilities/Avista Corp.	BBB/Negative/--	No	BB+/Stable/--	Yes
Idaho Power/IDACORP Inc.	A+/Stable/A-1	Yes	A-/Watch Neg/A-2	Yes
Arizona Public Service/Pinnacle West Capital Corp.	BBB+/Stable/A-2	No	BBB/Negative/A-2	No
Tucson Electric Power/UniSource Energy Corp.	BB/Stable/--	No	BB/Watch Neg/--	No
PacifiCorp/PacifiCorp Holdings Inc.	A/Stable/A-1	No	A-/Stable/A-2	No
Nevada Power Co. and Sierra Pacific Power/Sierra Pacific Resources	BBB+/Watch Neg/A-2	No	B+/Negative/--	Yes
Portland General Electric Co.	A/Watch Neg/A-1	No	BBB+/Watch Neg/A-2	Quasi
Public Service Co. of New Mexico	BBB-/Watch Neg	No	BBB/Stable/A-2	No
Southern California Edison Co.	A+/Watch Neg/A-1	No	BBB/Stable/A-2	Yes
Pacific Gas & Electric Co.	A+/Watch Neg/A-1	No	BBB-/Stable/--	Yes

Indeed, of the utilities surveyed by Standard & Poor's for this article, four companies have not implemented FPPA-- PacifiCorp (A-/Stable/A-2), Tucson Electric Power Co. (BB-/Watch Neg/--), Arizona Public Service Co. (APS; BBB/Negative/A-2), and Public Service Co. of New Mexico (BBB/Stable/A-2).

PacifiCorp serves portions of Utah, Oregon, Wyoming, Washington, Idaho, and California, has no FPPA in any of these states, and was adversely affected by the California crisis. As a result of an extended coal plant outage and overall reliance on the market for a portion of its power requirements, PacifiCorp deferred $537 million in power costs in 2001 and 2002, of which only $303 million were ultimately authorized for recovery, with Wyoming disallowing the bulk of this difference. As a result of this exposure, PacifiCorp's outlook was revised to negative, and the company was only recently returned to stable. While PacifiCorp has sought an FPPA in Wyoming, the Wyoming Public Service Commission has rejected its request, but did recently approve a settlement resulting from the company's July 2004 filing to increase rates due to rising wholesale power costs. Because about 21% of PacifiCorp's power in 2003 came from purchases, the lack of an FPPA is a credit concern.

In Arizona, the Arizona Corporation Commission (ACC) is allowed to authorize FPPA, but APS' and

Tucson Electric Power's were discontinued in the 1980s. As part of a settlement pending before the ACC, APS has negotiated an FPPA, which it requested in its June 2003 rate case filing. It is unclear whether the ACC will ultimately authorize one. APS' exposure to fuel and purchased-power is significant. In 2002, the ACC halted restructuring of the state's wholesale generation market. While it ordered APS not to sell its generation, APS was uncertain as to how it would procure power to meet retail loads. With electric sales rising about 4% per year, the utility estimates that by the summer of 2007, it will require a nearly 1,200 MW of new capacity, at least a portion of which is likely to be power purchases at indexed prices. Because of APS' significant short position in coming years, an FPPA could lower the utility's risk profile.

Since July 2000, Tucson Electric Power has been under a rate freeze that ends in 2008. Upward movement in gas or purchased power prices that exceeds its current rates does not qualify as sufficient reason to lift the cap. Tucson Electric Power's coal-fired generation provided 96% of the energy needed to serve retail load in 2003, and this low-cost resource base provides somewhat of a hedge against rapid cost escalation. However, a significant forced outage of one of its base load units or a run-up in coal prices with any coal contract reopeners represent exposures for the utility. (UniSource Energy Corp., Tucson Electric's parent, recently acquired the gas and electric distribution assets formerly owned by Citizens Communications. In conjunction with this purchase, the ACC approved an FPPA for these smaller operations, UNS Gas and UNS Electric.)

Public Service New Mexico faces circumstances similar to Tucson Electric Power's. It has no FPPA and in January 2003 negotiated a rate settlement that will lower rates 2.5% in 2005 and then hold rates constant until 2008. The utility owns generation that exceeds native loads, the majority of which is coal and nuclear.

FPPA Design and Implications for Credit Quality

While the use of FPPAs has become common, FPPAs are not uniform in design and consequently, their ability to protect utility credit quality varies. For example, some FPPAs are structured to insure cost recovery in a catastrophic market movement by capping a utility's exposure, but at the same time may have a relatively long lag time for a utility seeking to recover more mundane, month-over-month changes in costs. There are a number of features of FPPAs that are important for credit quality.

Triggers.

From a credit perspective, some of the strongest FPPA are found in the generation and transmission cooperative sector, where wholesale rates are often adjusted monthly. Such timely pass-through of fuel and purchased-power costs is rare in the IOU sector. Instead, IOU FPPA typically track costs in a balancing account, the amounts of which are not reflected in the retail rates as a charge or rebate until a predetermined threshold or trigger is hit. Clearly the lower the trigger, the more frequently the utility is able to adjust its rates to reflect cost changes.

Two contrasting examples can be found in California and Washington. In California, true-ups are not tied to an annual process. Assembly Bill 57, passed by the California state legislature in 2002, provides guidance to the California Public Utilities Commission (CPUC) as to how San Diego Gas & Electric Co., Pacific Gas & Electric Co., and Southern California Edison Co. are to recover procurement costs. Specifically, each year the utilities file their forecast fuel and purchased-power revenue requirements for CPUC review. (These forecasts exclude revenues collected for the California Department of Water Resource contracts). Once the forecast is approved, it is used to set rates. Deviations from the forecasts are tracked in a balancing account called the Energy Resource Recovery Account (ERRA). An adjustment to rates is triggered if the ERRA account is over- or undercollected by 5% of the utility's actual recorded generation revenues for the previous calendar year. This trigger, however, expires Jan. 1, 2006, after which there is uncertainty about what kind of mechanism will exist.

FPPAs may also be tied to dollar thresholds. The Washington Utility and Transportation Commission (WUTC) has approved an energy recovery mechanism for Avista Corp. that requires it to absorb the first $9 million of annual energy cost increases above base rates. Beyond this level, costs are deferred for later rebate and a surcharge is implemented when accumulated deferrals exceed 10% of base retail revenues. Alternatively, utilities may simply be subject to an annual reconciliation process in which actual versus forecast costs are used to adjust base rates. Idaho Power Co. (A-/Watch Neg/A-2) has such an approach.

Sharing mechanisms.

Commonly, FPPAs split the costs (savings) between the ratepayer and shareholder for fuel and purchased power that exceed a forecast range. For example, Puget Sound Energy Inc.'s FPPA requires that it absorb (or may benefit from) the first $20 million of increases (decreases) in actual versus forecast costs relative to baseline rates. For the next $40 million difference, 50% is borne by shareholders in the form of a FPPA adjustment, 10% of the next $80 million, and 5% of any amount more than $120 million, although through a temporary cap, Puget's exposure is limited through mid-2006.

Similarly, though more simply, APS' proposed power supply adjuster seeks a flat 90%/10% ratepayer/shareholder split in costs or savings. The same is true for Idaho Power's power cost adjustment. On balance, FPPAs that provide for fixed or high levels of ratepayer sharing are beneficial to credit quality because they trade upside benefit for downside protection.

Exposure caps.

Utility caps on losses are uncommon, but can be very useful for credit quality as they limit the utility's exposure resulting from extreme market volatility, which could otherwise erode financial health. For example, Public Service Co. of Colorado's (BBB/Stable/--) electric commodity adjustment limits the utility's maximum loss from fuel and purchased power expenses to $11.25 million. For the limited period from July 2002 through July 2006, the WUTC has provided Puget Sound Energy with a cap on its pretax exposure to purchased-power variations of a cumulative $40 million, plus 1% of the overage.

Prudency reviews.

Most FPPAs include caveats that allow the regulator to disallow costs if they are found to be imprudent. How complete this authority is determines how much the FPPA can be relied on, particularly in situations of extreme market volatility or when the utility is forced into the market to purchase replacement power to cover an owned plant outage. APS' proposed power supply adjuster is an example of a mechanism that gives regulators virtually unlimited authority to disallow costs. The ACC may elect to review the prudency of fuel and power purchases "at any time" and any costs flowed through the adjuster "shall be subject to refund if the Commission later determines that the costs were not prudently incurred."

By contrast, language that allows for prudency but provides the utility a high probability of recovery if certain guidelines are followed is preferable. One example is Nevada Power Co., whose recent experience with prudency disallowances of power purchases devastated its credit quality. Specifically, in March 2002, the Public Utilities Commission of Nevada disallowed $434 million of Nevada Power's purchased-power costs incurred during the energy crisis, causing the utility to lose access to bank lines of credit and to the unsecured credit markets. However, in November 2003, the PUCN approved an integrated resource plan (IRP) in which the company will get approval before entering into long-term PPAs. Its short-term power and fuel purchases are adjusted through a new base tariff energy rate, which has features that are similar to an FPPA. While base tariff energy rate costs are still subject to a prudence review, the IRP lays out clear risk-management guidelines, including value-at-risk limits and the use of certain derivative instruments that significantly mitigate the risks of disallowance if the company follows its IRP. Similarly, while California utilities could potentially face a reasonableness review along with its ERRA account, a disallowance is unlikely if the utility follows its procurement plans, which are preapproved by the CPUC.

How Quickly Recovery Is Collected in Retail Rates

Timeliness of recovery is important, as it can have implications for liquidity. California now has one of the strictest rules for timely response. The CPUC must act on a utility's request for an increase (assuming the trigger has been met) within 60 days of a filing. However, the CPUC has discretion in determining over what time period over- or under-collected balances are amortized.

In Arizona, deferrals could theoretically accumulate for long periods if amounts for collection exceed a surcharge cap but fall short of a safety net provision. If approved, APS' proposed PSA would be preset at a base rate of about 2.1 cents per kilowatt-hour (kWh). While actual costs above or below this level are tracked in a balancing account, true-ups occur only at year's end. At that time, rates are adjusted, but adjustments are constrained by the fact that they may not increase or decrease by more than 4 mills per kWh. However, APS may request the ACC to implement a special surcharge if the account reaches plus or minus $50 million at any time.

FPPA sunsets.

From a credit quality perspective, it is important to note that FPPAs are rarely established as a permanent component of a utility's rate structure. Thus, Standard & Poor's is mindful that FPPAs can be weakened or eliminated altogether once their initially authorized period expires. In the West, many of the FPPAs that have been implemented since 2002 have a sunset provision. For example, Puget Sound Energy, Public Service of Colorado, and California's three largest IOUs have FPPAs that expire Jan 1, 2006. If APS' proposal is approved, it will be in place for five years, at which time the ACC will conduct a review and determine whether it should continue. Another useful example is Portland General Electric Co. (BBB+/Watch Neg/A-2). The Oregon Public Utility Commission authorized a temporary FPPA to recover deferrals incurred in 2001 and 2002. The mechanism was discontinued in 2003. Today, the company has a quasi-FPPA; i.e., rates are updated annually through a resource valuation mechanism process, but if during the year the utility is unable to collect all of its costs through rates, it must make a special filing before the commission to recover the shortfalls. This experience highlights the fact that while many utilities may be currently protected through FPPA, this may not be the case for long.

Are FPPA the Holy Grail of Utility Credit Quality?

Standard & Poor's is frequently asked what weight is given to FPPA. It is clear that continued gas price volatility and upward trends in historically stable coal prices underscore the importance of FPPAs. Some western IOUs have sold their generation and will continue to rely on power purchases to meet retail load growth far into the future. However, it is also clear that FPPAs vary substantially in their ability to protect utilities daily and under catastrophic market movement. Moreover, it is critical to note that FPPAs are not a substitute for supportive regulation; the regulator's ability to disallow costs through ex-post prudency review, regardless of the existence of an FPPA, is a fact of life for utilities. But to the extent that an FPPA is transparent and well structured, regulators are likely to be less inclined to disallow a utility's fuel and purchased-power costs.

PacifiCorp
Exhibit UP&L _____(MTW-5)
Docket No. 05-035-___
Witness: Mark T. Widmer

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer

PCAM Scenario

November 2005

PacifiCorp
PCAM Scenario
100% Cost Reductions Returned to Customers, 90% of Cost Increases reecovered by Company
Utah's Allocated Share
(Assumes rates from Utah 03-2035-02 were in effect for all CY 2004)

		Scenarios		CY 2004 Actuals
	Total Company Net Power Costs ($)			
1	Actual Net Power Costs			745,626,531
2	Baseline Net Power Costs			512,000,000
3	**Total NPC Variance (line 1 - line 2)**			233,626,532
	PCAM GRID Studies			
4	Test Period Normalized Net Power Costs - Market Price Change			506,734,135
5	Test Period Normalized Net Power Costs - Actual Owned Hydro			548,190,627
6	Test Period Normalized Net Power Costs - Actual Mid-C			510,349,087
	Actual Hydro Generation (MWh)			
7	Company owned - West			3,230,154
8	Company owned - East			191,823
9	Mid Columbia			1,816,929
	Normalized Hydro Generation In Rates (MWh)			
10	Company owned - West			4,326,118
11	Company owned - East			509,838
12	Mid Columbia			1,921,760
	Hydro Generation Difference (Actual less Normalized MWh)			
13	Company Owned - West (line 7 - line 10)			(1,095,964)
14	Company Owned - East (line 8 - line 11)			(318,015)
15	Mid Columbia (line 9 - line 12)			(104,831)
	Total Additional NPC Cost / (Benefit) ($)			
16	Company Owned Hydro - West ((line 5 - line 4) X ((line 13 / (line 13 + line 14)			32,132,604
17	Company Owned Hydro - East ((line 5 - line 4) X ((line 14 / (line 13 + line 14)			9,323,889
18	Mid Columbia (line 6 - line 4)			3,614,952
19	Existing QF			9,702,753
20	New QF			1,944,987
21	All Other (line 3 - sum(line16:line20))			176,907,347
22	**Total**			233,626,532
	Dead Band		%	
23	Net Power Costs Variance Upper Dead Band		0.00%	512,000,000
24	Net Power Costs Variance Lower Dead Band		0.00%	512,000,000
25	Net Power Costs Variance in excess of Dead Band			233,626,532
26	Excess NPC Variance % of Total NPC Variance (line 24 / line 3)			100%
		NPC Variance		
	Customer /Company Sharing Ratio	> 0	< 0	
27	Customer Sharing %	90%	100%	90%
28	Company Sharing %	10%	0%	10%
29	**Customer % of Total Net Power Costs Variance (QFs & 100%)**			**90%**
30	**Shareholder % of Total Net Power Costs Variance**			**10%**
	Customer Share Additional NPC Cost / (Benefit) ($)			
31	Company Owned Hydro - West (line 16 X line 29)			28,919,343
32	Company Owned Hydro - East (line 17 X line 29)			8,391,500
33	Mid Columbia (line 18 X line 29)			3,253,457
34	Existing QF (line 19 X 100%)			9,702,753
35	New QF (line 20 X 100%)			1,944,987
36	All Other (line 21 X line 29)			159,216,612
37	**Total Customer Share**			211,428,652
	Company Share Additional NPC Cost / (Benefit) ($)			
38	**Total Company Share (line 3 - line 37)**			22,197,879
	Utah Allocated Share ($)	MSP Factor	CY 2004 %	
39	Company Owned Hydro - West	DGP	0.0000%	0
40	Company Owned Hydro - East	SG	39.2437%	3,293,136
41	Mid Columbia	MC	11.3920%	370,635
42	Existing QF	Situs		5,504,270
43	New QF	SG	39.2437%	763,285
44	All Other	SG	39.2437%	62,482,512
45	**Total Utah PCAM Adjustment**			72,413,838
46	Retail Revenue Adjustment (power production rate .03209 per kilowatt hour multiplied by difference between the actual and base retail kilowatt-hour sales 1,274,676			(40,904,358)
47	**Total Utah PCAM Adjustment**			31,509,480

PacifiCorp
PCAM Scenario
100% Cost Reductions Returned to Customers, 90% of Cost Increases reecovered by Company
Utah's Allocated Share
(Assumes rates from Utah 03-2035-02 were in effect for all CY 2004)

	Scenarios	CY 2004 Actuals
Total Company Net Power Costs ($)		
1 Actual Net Power Costs		745,626,531
2 Baseline Net Power Costs		512,000,000
3 **Total NPC Variance (line 1 - line 2)**		233,626,532